IPTC-18108-MS

Key Factors Differentiate the Success Rate of Coalbed Methane Pilots Outside of North America - Some Australian Experiences

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This paper was prepared for presentation at the International Petroleum Technology Conference held in Kuala Lumpur, Malaysia, 10–12 December 2014.

Abstract

Coalbed methane (CBM) has been considered a relatively mature unconventional gas resource in North America. In Australia, where the CBM or coal seam gas (CSG) industry is nearly two decades old, there have been successful and unsuccessful pilot projects and resources have been slower to develop after nearly twenty-five years since North American technologies were exported internationally. Thus, it is reasonable to believe that there are differences outside North America that have hindered CBM development in Australia.

Often CBM pilots owe their degree of success to one of three major factors: geologic or structural setting, reservoir properties, or completion strategies. Most pilot testing have been conducted either to characterize the production from a particular geo-domain associated with certain perceived geological risk and uncertainty or to estimate potential project reserves to a reasonable degree of accuracy. This need to reduce uncertainty is more pronounced in Australia based on the need to balance development decisions, tenure retention requirements, whilst minimising the risk for the upcoming development phase.

Often in hindsight, the opportunity to increase the chance of success for good areas or reduce the expenditures in poor areas was achievable through improved reservoir characterisation or better pilot planning. In some cases, the resource volumes are large, but the progression of resources to reserves has been less certainty based on challenges. In this paper we will highlight some key observations from several Australian CSG pilots that led to success or challenges for each case. The authors' goals are to identify key indicators, which if recognised earlier may have increased the rate of success or reduced unnecessary expenditures in these pilot areas.

Background

CBM has become an increasingly important component of Australian gas production whilst much of the current production in the North America is in decline in preference to shale gas. As the shale gas resources in Australia are less mature and there exists extensive, gas-charged coal resources in Australia, CBM production has been growing and is now planned to deliver the gas required for three two-train LNG projects in Gladstone to deliver shipments in 2014 and 2015. Whist some of the reservoir and development characteristics that contributed to commercial success in CBM projects in the North America are the same for Australia, we will highlight some of the differences that continue to challenge Australian projects going forward.

In a general, most CBM projects are marginal economic prospects with great emphasis placed on reducing development and operating costs to maintain economic viability. Certainly there are notable exceptions to this in both in North America and Australia such as the fairway of the San Juan Basin in the US and the Peat/Scotia, Fairview and Undulla Nose areas in Australia, where in some sections production is more typical of conventional gas wells. Generally, completion strategies from North America cannot be directly transferred to Australia's stress regime without some tweaking. However, one of the successful completions in fairway of the San Juan Basin, cavitation, has also found success in applications in the Fairview Field of the central Bowen Basin.

Thus, commercial success or risk from coal reservoirs generally involves reservoir quality (bulk permeability) or economic parameters (e.g., gas price, low development costs, etc.). The remainder of this section will discuss the exploration, reservoir characterisation, completion, and field developmental considerations important to and associated with commercially successful CBM projects. This paper will highlight some key observations from developments in the northern Bowen, central Bowen and Surat Basins where such factors led to success or challenges for each case. In the course we will identify key indicators, which if recognised earlier may have increased the rate of success or reduced unnecessary expenditures in these pilot areas. However, before embarking on a review of individual areas or projects, it is good to review the general maturation cycle of CBM projects and the levels of uncertainty that must be addressed at each stage of the process to ensure a successful project.

CBM Project Maturation Timelines and Uncertainties

It's important to review the CBM project maturation timeline and understand what forecasting capabilities and uncertainties exist during each point of the process. In the exploration stage, scoping for potential, CBM developments involves identifying areas with contiguous coal sections and sufficient gas in place per well to support commercial production. Most prospective areas can be delineated using geologic data and coal quality information available from preceding conventional oil and gas or coal mining, exploration or development projects. Better information regarding net target coal is generally available for prospective underground coal mining areas, as it is a key determinant on their project success. Data may be obtained from outcrop studies or from well logs run in conventional oil and gas wells that have penetrated the coals.

Next, appraisal strategies must be implemented that confirm the resource potential and potential productivity of these areas by direct measurement of key reservoir properties and pilot production testing. Key reservoir properties (e.g., adsorbed gas content, coal quality, and gas diffusion properties) may have been gathered on a limited basis or inferred from other data must directly measured from coal samples or coring. Whilst additional coring and establishing and producing pilots is a relatively high expense for an early project, it is essential in gathering the data to develop CBM resources and project potential recovery factors per well.

Once areas of CBM contingent resources are identified, an initial development strategy for providing a long term resource to a sustaining market must be determined and drilling and testing of multiple pilot programmes of well completed. These pilot programmes further delineate key coal characteristics (e.g., gas content, permeability) and widely test well completion methods to full-scale development. Often, multiple five-producing well patterns delivering field gas to local power generation or field gathering systems are able to prove the long-term gas production potential of these areas and prove the reserves potential for further development.

The ultimate number of pilots and number of wells per pilot are that number which may be necessary to develop interference between offsetting wells and demonstrate effective dewatering of the reservoir to establish gas production around the center well of each multi-well pilot. For relatively large prospective areas, this may require several multi-well patterns to establish the production potential of the prospect area and at varying well spacings to understand the potential drainage area required for full-scale development. Finally, as operating costs for CBM wells are generally higher than conventional gas wells the quantities and quality of the produced water should be monitored closely during this stage of the project to quantify the necessary water management strategy and its associated cost parameters for the final development.

Experience from analysis of coal seam projects worldwide indicates the more important reservoir parameters controlling gas productivity include: (1) permeability (fracture/cleat system), (2) gas content, (3) well spacing, (4) initial gas and water saturation in the fracture/cleat system, and (5) the relationship between reservoir pressure and flowing well pressure (Johnson, Hopkins and Zuber 2000). However, without the proper completion in place, these relationships can be masked and give misrepresentative pilot production data and delay the project (Johnson, Scott and Herrington 2006). Thus, trials of multiple completion strategies should be completed during this appraisal stage in order that a go-forward strategy can be applied at the development scale with appropriate economies of scale in logistics and operational areas.

Once the initial development or developmental pilots are completed, then process of delivering the value of the project is dependent on taking advantage of economies of scale and allowing as many costs as possible to be spread over all the development wells. Costs that may fall into this category include: water management costs (e.g., gathering, storage, beneficial usage determinations, disposal, etc.); gas gathering to include flexible ‘fit-for-purpose’ field compression capabilities over the life of the well; as well as final processing, compression and overall project management costs.

The highest costs in a CBM developments are drilling and completion, surface gathering, compression and operating costs mostly in the form of water treatment and disposal. Drilling and completion strategies must be fully developed in the pilot stage to take advantage of economies of scale in rig movements, stimulation requirements, logistics and operations. Without a firm strategy, a ‘factory approach’ cannot be implemented and tweaked to achieve optimal efficiency. Thus, as a result of lower field pressures, artificial lift, and produced water management, a CBM project’s operating costs are generally higher than conventional gas wells; therefore, automation and surveillance are key elements to maintaining field efficiencies and minimizing well work overs as much as possible over the life of individual well production areas.

Finally, continuing diligence and evaluation needs to be made to assure the highest confidence of achieving the highest deliverability in the most optimal areas and in the most efficient well spacings. Uncertainties will continue to remain in a project until the most attractive areas are drilled, as most CBM projects are statistical plays. However, with modern simulators and computational abilities, methods are available to test assumptions and assure that variables with the highest sensitivity to ongoing outcomes are identified and monitored (Philpot et al. 2013).

Consequently, each phase of a CBM project has objectives, data acquisition and processing capabilities, and forecasting tools that can reduce the uncertainty of the project as it progresses and are outlined in the following table.

Based on the framework outlined in Table 1, we can now evaluate each area for successes, setbacks, and future challenges to developments.

Bowen Basin Project Reviews

The Bowen Basin is one of the largest thermal and coking grade coal-producing regions of Australia. Further, the area has been the site of a number of coal mining related fatalities as a result of the high gas contents. The primary coal producing region is the northern Bowen Basin, which has historically flared and vented the gas from its extensive underground mining projects. The combination of mining and ongoing CBM data has led to a better understanding of the Bowen Basin’s geology further enhancing CBM exploration activities (Esterle, Sliwa and CSIRO 2002).

Table 1—Objectives, data and forecasting capabilities at differing stages of the CBM project maturation timeline

Activity	Exploration	Appraise	Development Pilot/Initial Development	Full Scale Development
Objective	Screen exploration acreage for highest potential	Confirm production potential, trial well completion methods	Characterise longer term production trends, fine tune well design and create initial development hub for larger scale development	Maximise the value of the resource through development
Data Acquired or Processed	Coal depth, thickness, gas content, saturation, reservoir pressure, permeability	Production and producibility, effectiveness of the well completion, operational performance, water quantity/quality, gas composition	Longer term gas and water rates on development scale, reservoir pressure response	Field wide production, detailed geological and reservoir data from development wells, reservoir pressure from production and observation wells
Forecasting Tools	Analogy, volume and decline estimates	Volume and decline estimates, simple single well model	Simple sector modelling with site specific reservoir parameters and simple history match of the initial pilot	Full field reservoir model with a history match of the small scale development

If we review the northern Bowen Basin, we know that western portion or shelf of the northern Bowen Basin is considered more attractive for both mining and CBM based on large consistent structures. This is unlike the eastern portion of the Basin that is highly faulted and folded and limited to surface mining operations near subcrops and outcrops, based on limited geological control. In the western portion or shelf of the Northern Bowen Basin lie the areas of the Broadmeadow and Moranbah Gas Project (MGP) areas. Unlike the northern Bowen Basin, the central Bowen Basin is dominated by large fields some on anticlinal positions– the Moura, Spring Gully/Fairview, and Peat Scotia Fields. Each is a separate structure that expresses a dominant geological feature of the Bowen Basin. We will briefly review the main areas and comment on key aspects of their development.

Broadmeadow Pilot Area, Northern Bowen Basin

The Broadmeadow pilot was one of the first CBM pilots and was attempted in the Northern Bowen Basin in 1987, completing ten wells with seven having injection testing or frac treatments (see Figure 1, just north of Grosvenor/Moranbah Fields). The main drawbacks to the project's success were: (i) high instantaneous shut-in pressure (ISIP) frac gradients (0.96-1.49 psi/ft); (ii) high closure gradients from dead strings (0.89-1.0 psi/ft); (iii) permeability values ranging from 0.2-1.51 mD with skins of 0.24-0.44, respectively; and (iv) overall low production rates with maximum well production of 60-123 Mscf/day on the best two well (Reeves and O'Neill 1989). Understandably this was the first pilot in the area and many lessons learnt in the process were taken up by subsequent operators in the Northern Bowen Basin. However, until CH4 Pty Ltd (later operated by Arrow Energy Pty Ltd or Arrow Energy) drilled lateral wells in the area, specifically designed for CBM production, was the true potential of the area unlocked.

Moranbah Gas Project, Northern Bowen Basin

The history of the Moranbah Gas started with the first two single lateral pilots drilled and production tested in the year 2002. Following the success of the early productivity tests, the company (CH4 Pty Ltd) decided to proceed with the commercial development of the Arrow Energy, Moranbah Gas Project (MGP) in the year 2004, which included the first dedicated CBM gas pipeline from the field to multiuser market, Townsville QLD for electric generation.

The in-seam drainage technique used in the MGP has been developed from coal mining gas pre-drainage from Queensland and NSW mines. There gas pre-drainage is undertaken with guided horizontal in-seam boreholes often drilled along planned development roadways and can extend and connect multiple drain holes along the planned longwall. In MGP horizontal wells or laterals are primarily used

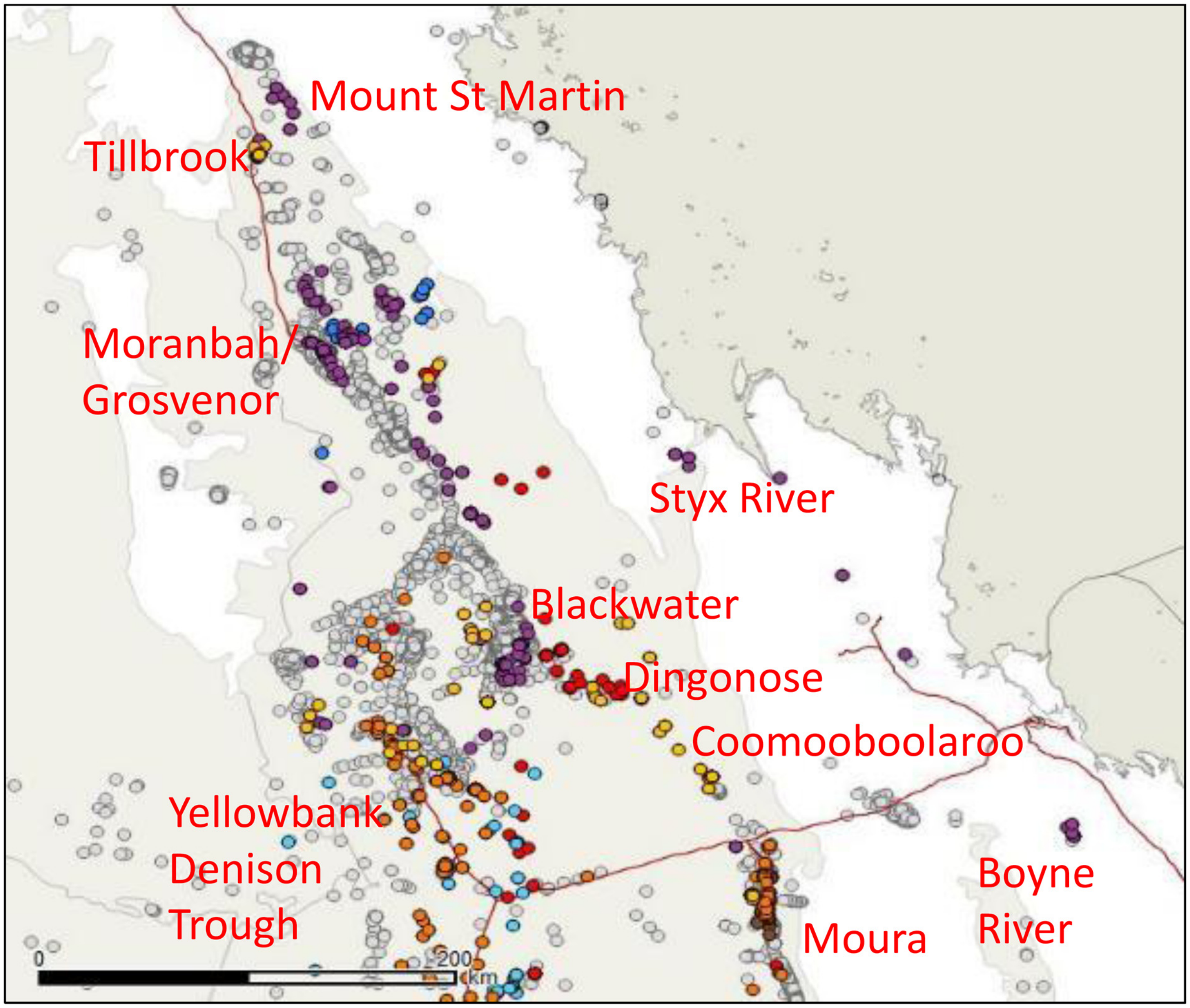

Figure 1—Wells by operator or drilled since Jan 2010 - Source IHS database

to describe “in-seam” drilling, where a well trajectory is maintained within a single coal seam or package. A surface-to-in-seam (SIS) horizontal well is drilled from surface to the target coal seam and then geo-steered in-seam to intersect a previously drilled vertical well. The horizontal well is oriented down dip towards the vertical well and provides a pathway for both gas and water to migrate towards the vertical well. The vertical well is the producer and provides separation of gas (tubing/production casing annulus), water (tubing) and solids (sump) (See Figure 2).

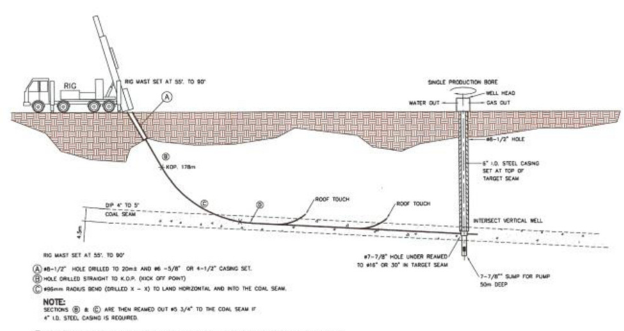

Figure 2—Depiction of Surface-to-Inseam (SIS) well

In MGP, the SIS dual-forked or ‘chevron’ well is the most common well type with ~200 such wells drilled (see Figure 3). Single-seam multi-lateral wells increase production rate and improve drainage efficiency in the same way as in-seam horizontals and are extensively used in mining, gas pre-drainage. However, the ‘chevrons’ increase the drainage efficiency allowing multiple laterals to access a single vertical production bore. Any number of laterals can be employed e.g. dual, tri- and quad-laterals. In the MGP, however, two laterals is the maximum number of attempted completions per seam.

The benefits are that horizontal wells are designed to maximize coal seam exposure to the wellbore, resulting in:

- higher rates due to increased exposure to productive cleating;
- higher recovery factors due to increased drainage efficiency due to better contact with the reservoir;
- the ability to mitigate against uncertainties in cleat orientation/permeability anisotropy; and
- the ability to maintain total in-seam 'yardage' (or reservoir exposure) while reducing the total number and cost of producing wells and associated infrastructure.

The limitations of a horizontal concept include:

- higher drilling and surface infrastructure capital expenditure per well;
- intensive land access requirements;
- requirements for a single, laterally extensive and continuous seam;
- ranging laterals to intersect the vertical drainage well can be risky and limits the overall achievable length; and
- limited completion options within the lateral, particularly in mining regions where the installation of metal liners or completion accessories in the lateral may be prohibited.

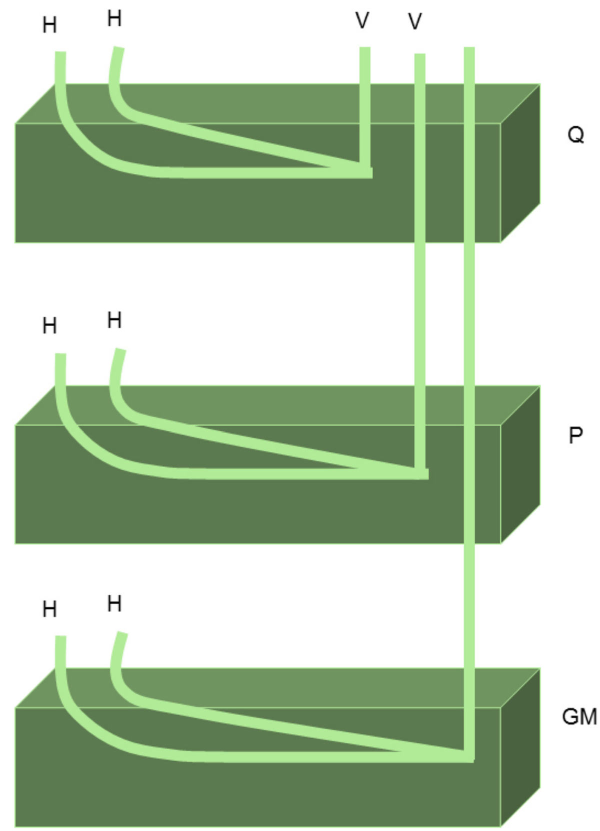

Figure 3—Depiction of 'chevron' wells in the 'Q', 'P', and 'GM' seams in the Moranbah Gas Project

However in recent times a concept shift was required to maximise the value of MGP as:

- the historical SIS well concept got increasingly challenged by the reservoir/economic environment; and
- there is a shift towards increasing exposure with depth in effort to maximise recovery.

Despite increasing challenges, the data and models from existing development wells, analogues and reservoir modeling still suggests that horizontal wells remain the favoured development concept over hydraulic fracture stimulated verticals.

Moura/Dawson River Area Fields, Central Bowen Basin

Moura (see Figure 1) like many other Bowen Basin mining areas was initially developed from high-wall and underground pre-drainage through in-seam laterals to reduce gas and prevent outbursts (Gray 1983, Gray 1987a, Gray 1987b). Moura underground explosion raised awareness of gas drainage and provided the impetus for increased gas drainage; however, despite increased drainage, an explosion in the Moura No. 2 underground coal mine on 7 August 1994 resulted in eleven miners perishing and the mine was sealed at the surface.

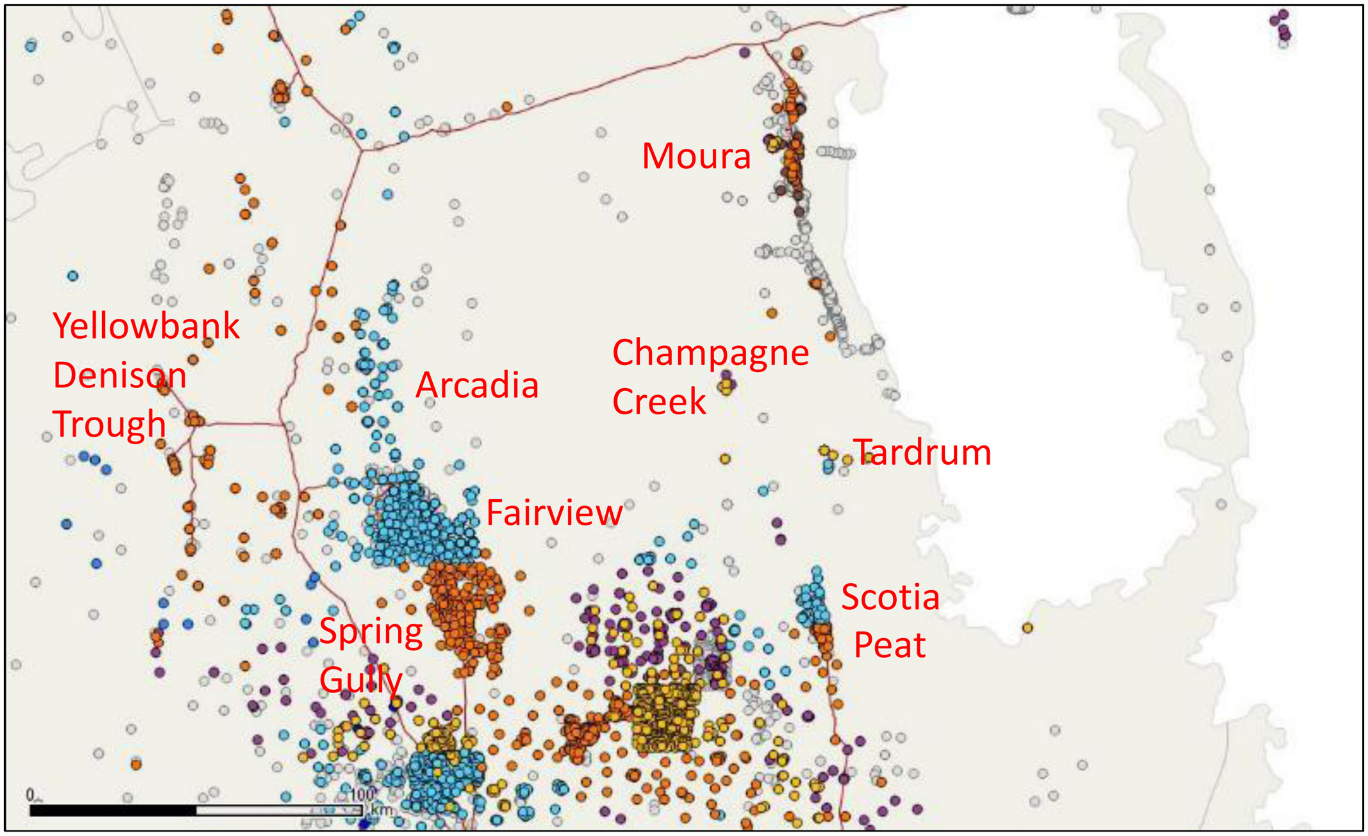

Figure 4—Central Bowen Basin wells by operator or drilled since Jan 2010 - Source IHS database

Early development of CBM production around the Moura/Dawson River Area Fields was made by Conoco then Oil Company of Australia, initially developing the area with hydraulic fracturing, first with foam fracs then ultimately water fracs (Morales and Davidson 1993). In 2007, a look back study noted inconsistent, multi-seam production variability after a series of production logs were made (McMillan and Palanyk 2007); this resulted in a shift to SIS wells in key areas focusing on the main intervals of productivity.

Variability in well trajectory and fines production create production optimization opportunities in these wells, most of which are operated by Westside Petroleum, and will deliver gas to the Santos Ltd/GLNG Project. The author believes there is opportunity in this area to revisit hydraulic fracturing in vertical wells and re-fracturing of prior producers now that de-stressing may have occurred. Despite continuing success in the main producing area, there has been limited success expanding the producing trend north, south or westward, where depths and stress increase, often from tectonic strain increases off-structure.

Fairview/Spring Gully Fields, Central Bowen Basin

The Fairview pilot (see Figure 4) was the first CBM pilot attempted in the Central Bowen Basin since the mid-1990s with first gas delivered in 1998. Reserves have been reported per well in the 2.5-3.5 Bscf/well based on an average net thickness of coal of 50-100 ft and 200-400 scf/ton (Jenkins and Boyer 2008), not unreasonably estimates for many fields in the central Bowen Basin area. The Spring Gully project evolved from two discovery wells in the previous Durham Ranch Field, subsequently renamed Spring Gully by the next operator, Origin Energy (Origin). Fairview lies on the apex of the Comet platform, whilst the adjoining Spring Gully Project encompasses the southern end of the platform and the extensional slope to the south and east.

Cavitation completions were highly successful in the early Fairview wells operated by Tri-Star Petroleum, a rare recipe for success outside of the San Juan Basin. This technique was implemented by

Tri-Star personnel who had previous experience, successfully completing wells in the San Juan Basin using this technique (Vaziri et al. 1997). Over time the current operator, Santos Ltd (Santos), has evolved to trialling varying hydraulic fracturing completions in an attempt to unlock lower permeability areas off the main structure. Spring Gully, initially developed under the Oil Company of Australia (OCA) and now operated as Origin/APLNG, took a more aggressive stance on hydraulic fracturing since the project startup based on mixed success with cavitation in the early Tri-Star Durham Ranch wells.

Early OCA/Origin operations completed roughly 50% of the early wells successfully with hydraulic fracturing. Over time, Spring Gully has also failed to develop much deeper south, west and eastward from the extensional slope structure coming off the Comet Platform. Further, Blue Energy to the south and west of Spring Gully has noted thick coals and good gas content but low rates following test and without stimulation. Again, it appears that depth and increasing stress make completions more difficult off the main Comet Platform area and their respective extensional slopes.

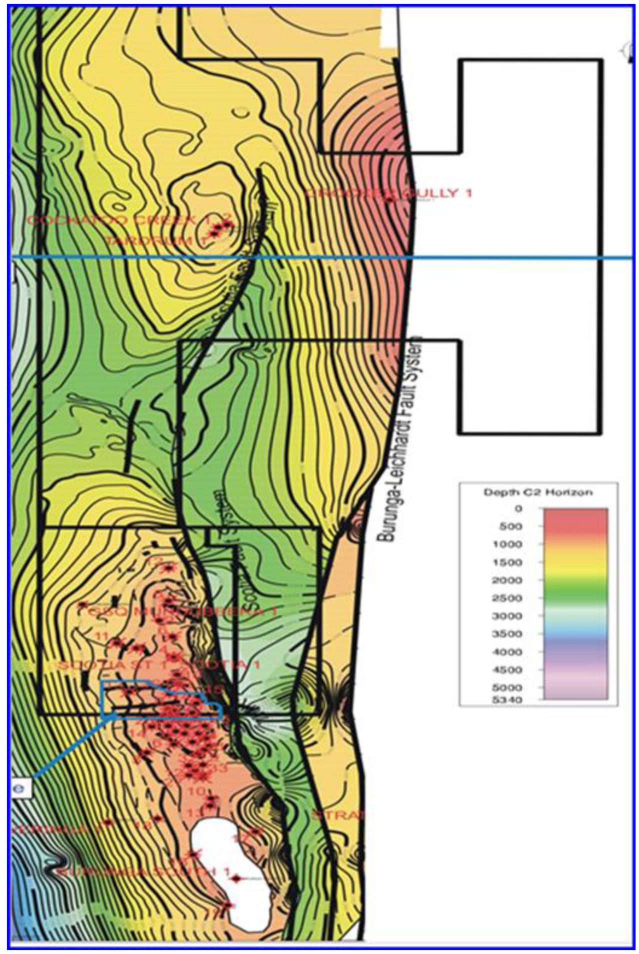

Figure 5—Depth contours of the Burunga Anticline showing initial OCA/Santos development wells (After Johnson et al., SPE 77824, 2002)

Peat/Scotia Fields, Central Bowen Basin

The Peat/Scotia Fields (see Figure 4) were the first CBM producing fields for OCA/Origin and Santos. Both fields are located on the Burunga Anticline, adjoining the Leichardt-Burunga Fault, a major structural feature positively affecting a number of oil and gas fields as it extends southward near the Undulla Nose and turning towards the Moonie Field in the Surat Basin (see Figure 5). Cavitation completions were initially trialled by Pacific Oil and Gas, prior to OCA, and Santos but excessive fines influx, hole sloughing and less overall production to later hydraulically fractured wells was observed, resulting in a move to cased hole completions to meet growing opportunities to sell gas into the eastern Queensland emerging gas markets.

Both OCA and Santos progressed the field initially very successfully with nitrogen foam fracturing fluids, then switching to water frac treatments when there was less pressure for immediate production to fuel the high demand from initial developments on both fields. The structure is highly extensional, exhibits near conventional well performance, but has demonstrated pressure dependent leakoff and anomalous post-frac shear events in the wellbores during and after hydraulic fracturing (Johnson, Flottman and Campagna 2003, Badri et al. 2000).

Near conventional behavior on these highly permeable structures allowed wider spacing and reduced need for infill wells to achieve effective interference and drainage; however, as with the Comet Platform, attempts to move too nearby structures (e.g., Cockatoo Creek/Tardrum) have met with limited extent beyond the extensional slopes. The Tardrum Field, has had numerous operators since Conoco in the early-1990s, Santos in the early-2000s, then Sunshine (acquired by QGC Pty Ltd) each making an attempt to develop the structure; unfortunately, higher stresses and lower permeability values exist in the area

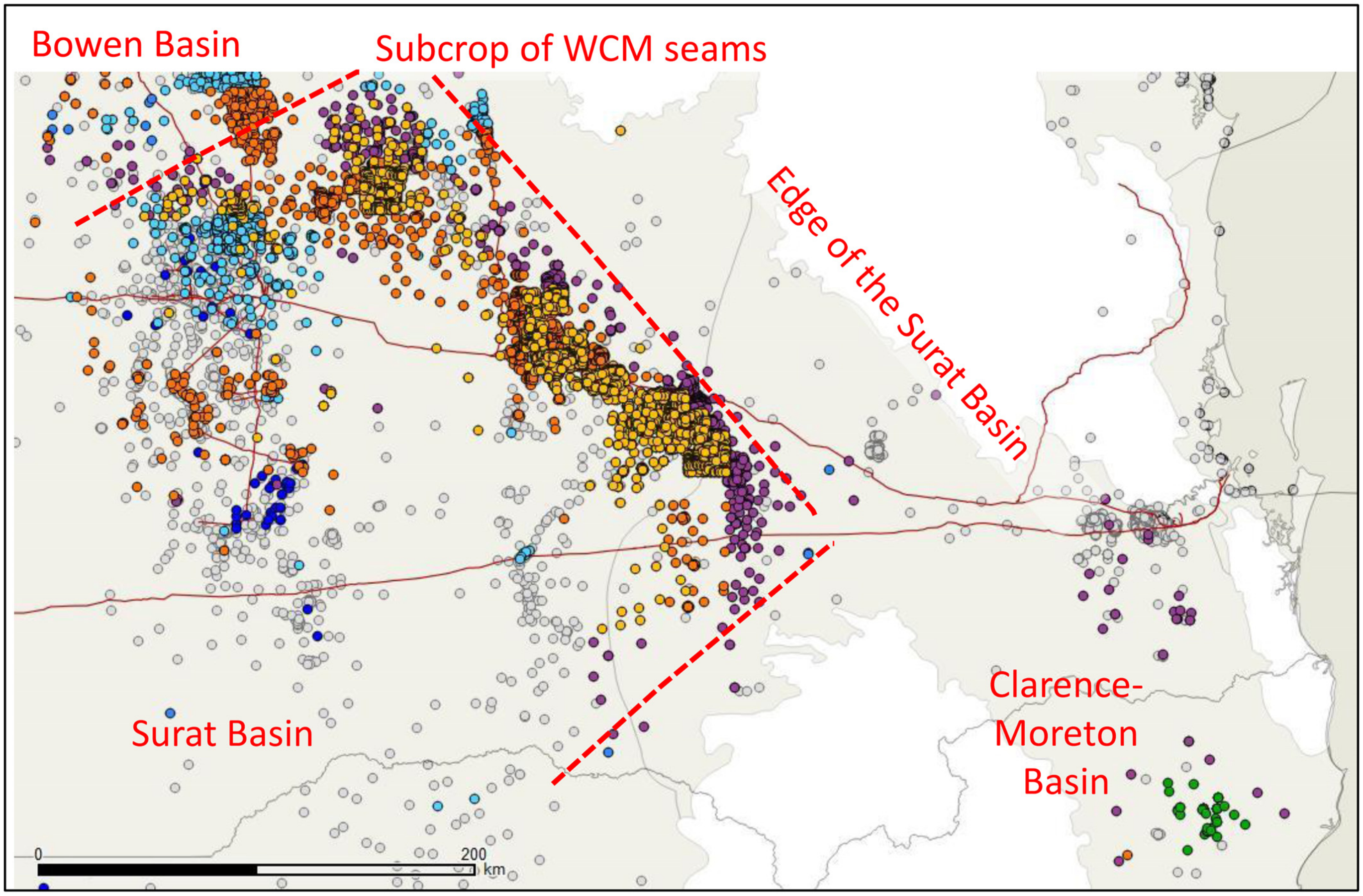

Figure 6—Wells by operator or drilled since Jan 2010 - Source IHS database

resulting in poor post-hydraulic fracturing results from early attempts despite effective placement of relatively large sand volumes in each well using nitrogen foamed fluids.

Outlying Fields, Northern and Central Bowen Basin

All Bowen Basin operators have attempted at one time or another some of the coal-rich but challenging off structure areas of the Bowen Basin using completions with hydraulic fracturing. Like the Broad-meadow pilot, these fields generally high exhibit high ISIP values as a result of near wellbore effects, high closure stress values as a result of high tectonic strains, and modest initial rates that make the wells sub economic to develop at current domestic gas prices.

However, more diagnostics are being used by all operators, with Arrow Energy reporting results of the use of diagnostic fracture injection test (DFIT) data to not only build local mechanical earth models to understand fracture behavior and upscale those findings to regional stress mapping to determine the best potential geo-regions for targeting future wells (Alboub et al. 2013, Gibson et al. 2013). If similar diagnostics to those employed in the Surat Basin indicate large stimulated reservoir volumes (SRV) can be created in these areas, then techniques, strategies and potentially novel technologies being discussed for implementation in the Surat Basin later in this paper may unlock areas of higher stress in the Bowen Basin.

Surat Basin Project Reviews

Whilst the Surat Basin has been a prolific producer of conventional oil and gas, the development of the Jurassic Walloon Coal Measures (WCM) has only been since the early-2000s and represent areas of the highest drilling in the Basin (see Figure 6). The first two operators, QGC Pty Limited (now QGC, a BG

Group business or QGC) and Arrow Energy began exploration based on logs from deeper petroleum exploration wells; coal exploration wells and water bore data. A majority of the data was based on bores that were shallow (<200 m) and most (>80%) had no wireline log data; however, they were able to determine the subcrop of the coal measures and provide some indicative coal quality data. A small number of this exploration bores had gas shows during drilling and an even smaller percentage of these produced gas flows during drilling.

Over a decade the WCM proceeded from a broadly based exploration-drilling program to prove a potential resource by a small number of junior operators to a major project area operated by or in conjunction with major international proponents planning to deliver CBM to three LNG projects, each operating two trains. The main project areas to be discussed in this paper are the Undulla Nose area, largely operated by QGC and Origin Energy, and the Daandine area operated by Arrow Energy. For completeness, the authors will briefly describe the Chinchilla/Goondiwindi Slope Area which is an area of many unsuccessful pilots by a number of operators, but which remains a large region of untapped CBM resources.

Undulla Nose, Surat Basin

The first project area to be discussed in the Surat Basin is the Undulla Nose area, largely operated by QGC and Origin Energy. The Undulla Nose is a structural play with the feature encompassing the Berwyndale South, Argyle and Lauren Gas Fields, in addition to a substantial area of QGC's and Origin's exploration tenements beyond. The Origin Energy operated fields are mostly to the West of Berwyndale South and is known as Talinga.

The Berwyndale South and Talinga Gas Fields operate in many ways like a conventional structural play with free gas trapped at the crestal part of the plunging nose. Alongside the plunging structure, the Undulla Nose is also blessed with thick coal seams (over 29m net), enhanced permeability (mostly due to flexure and extensional forces at the crest) and high gas saturation. For example, in very early days at Berwyndale South, QGC had: eleven wells producing over 1 MMscf/d, four of which were producing over 1.5 MMscf/d with two producing in excess of 3 MMscf/d; and 40% of the producing wells on the gas field do not require any pumping. The average well flow rate of the wells drilled at Berwyndale South Gas Field was over 1 MMscf/d with sustained high flow rates. The production characteristics of these wells are atypical of other CBM wells in the Surat Basin in the WCM.

However, it is worth noting that away from the structural enhancement the permeability tends to drop off rapidly leading to a need for stimulation. Some of the Origin operated blocks in southern extent of the Undulla Nose down dip of Condabri Central and North would require some form of stimulation in order to produce at commercial rates. In areas north and east of Undulla Nose (e.g., North Orana and South West of Baking Board) WCM permeability values have been reported to be extremely high with low gas saturations (e.g., <30%). This area highlights the importance of gas saturations (>65%) alongside permeability for commercial production (see Figure 7).

An important element to the success in this area was a drilling and completion technique developed by QGC (Johnson et al. 2006) with ongoing optimizations by both QGC and Origin to enhance gas production. The drilling and completion technique primarily used is the most common open-hole completion used in the WCM and uses pre-perforated or pre-slotted liner sections placed in the openhole WCM, protected and isolated from overlying intervals by an external casing packer and cement back to surface. Prior to setting the liner, casing, ECP and cementing, under-reaming of the coal sections was an early practice prevalent amongst all the operators. Today, with additional care in drilling practices, depressurization and in slightly lower permeability areas, the benefits of under-reaming are not as apparent and is being reviewed on a cost/benefit basis using dedicated pilot studies by most operators.

An area of continuing research and further potential upside for production optimization is the potential to reduce fines production by improved completion designs. The WCM like many coals produces some

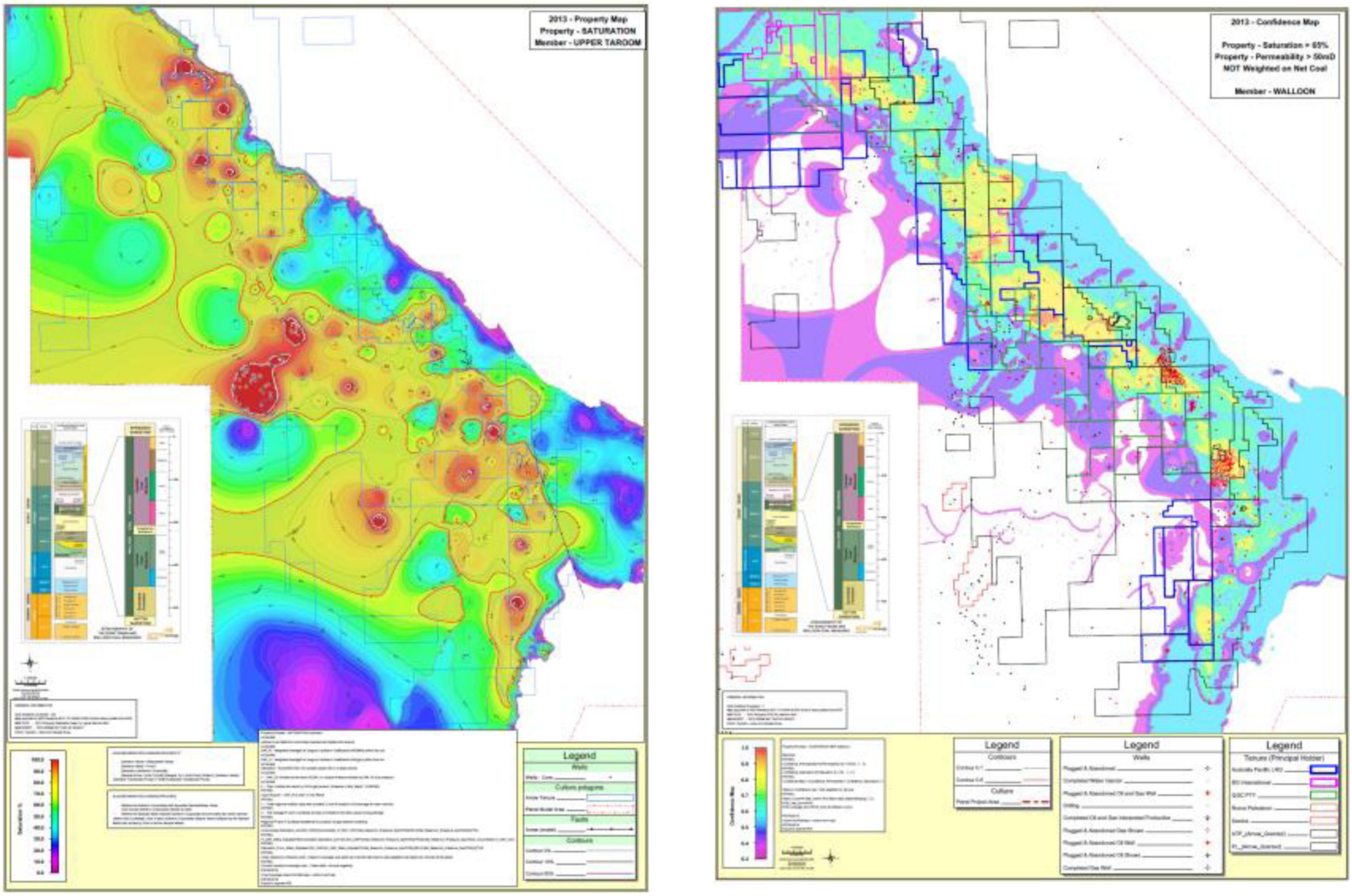

Figure 7—Permeability and gas saturation distribution in the Walloon Coal Measures (WCM) along the eastern Surat Basin

coal fines; however, the very thick, clay-rich interburden and low net-to-gross coal (e.g., 10%) distribution of coal in the interval has led to a degradation of the interburden in these lined, open hole completions and especially if wells are left static with low salinity, bicarbonate-rich, WCM produced water. In some areas, periodic work overs and extensive clean outs after shut-ins are required to resume productivity levels noted after the post-drilling clean-out and completion.

Currently, the mechanisms of fines production are being studied, and once understood, then more effective strategies for management can be employed. Strategies have been implemented to address fines by mechanically isolating areas of fines production using cement baskets, screens, and swell packers and in replacing WCM with KCl brines during periods of well shut-in. However, mechanical measures require additional costs, planning and real-time design based on lack of seam predictability, all of which can delay a very efficient drilling operation in the development phase. Early trials by operators at gravel packing failed as the gavel pack builds additional skin around the well bore over time, based on the wide distribution of interburden fines and rhombahedral structure of inter-mixed coal fines.

Daandine Field, Surat Basin

The Daandine field is one of the most successful areas in the Surat Basin operated by Arrow Pty Ltd. The Daandine gas field is 40 km West of Dalby and has been producing gas since September 2006. Early production started with 2 wells in 2005. First commercial production was delivered at the end of 2005. Thirty-two Juandah seam wells were added between 2006 and 2007. Thirty-three Taroom seam and forty-two commingled WCM wells have been added since 2007, some of them showing the highest production performance within the Arrow operated fields in Surat. Production performance of the Daandine field has been dominated by high producing commingled wells.

The WCM in this area has net coal thickness of about 25 m. While permeability values are in the order of 100-200 mD, the gas saturation is in excess of 80% in most parts of Daandine and Stratheden areas. In contrast to the Undulla Nose area, the Daandine Field is structurally benign. An average comingled well in Daandine peaks at about 3 MMscf/d. Initial development in Daandine only had wells completed in the shallow Juandah seams of the WCM, but as the development progressed, comingled completions including the Taroom seams turned out to be the most productive, an early key learning in the Undulla Nose area.

A recent study by Arrow Energy has also shown that the member seams in Daandine are laterally continuous (up to 5km) and could be one of the reasons contributing towards the productivity of the field. Studies led by both QGC and Origin Energy highlight the importance of the lateral continuity of the member seams in the WCM being one of the key drivers alongside thickness, permeability and gas saturations. In terms of well spacing, the initial development was laid out at 140 acres well spacing with vertical wells only. Arrow has successfully trialed the "deviated wells from pad" technology, which optimizes the surface gathering by collocating the producers in a pad on the surface. Deviated wells from pads form the basis of wells design of the ongoing Daandine Expansion Project. The presence of lateral continuity has significant implications in terms of development decisions around well type and spacing, so identifying it early can yield significant benefits for a project development and can allow an operator to take advantage of these characteristics as Arrow has with the "deviated wells from pad" technology.

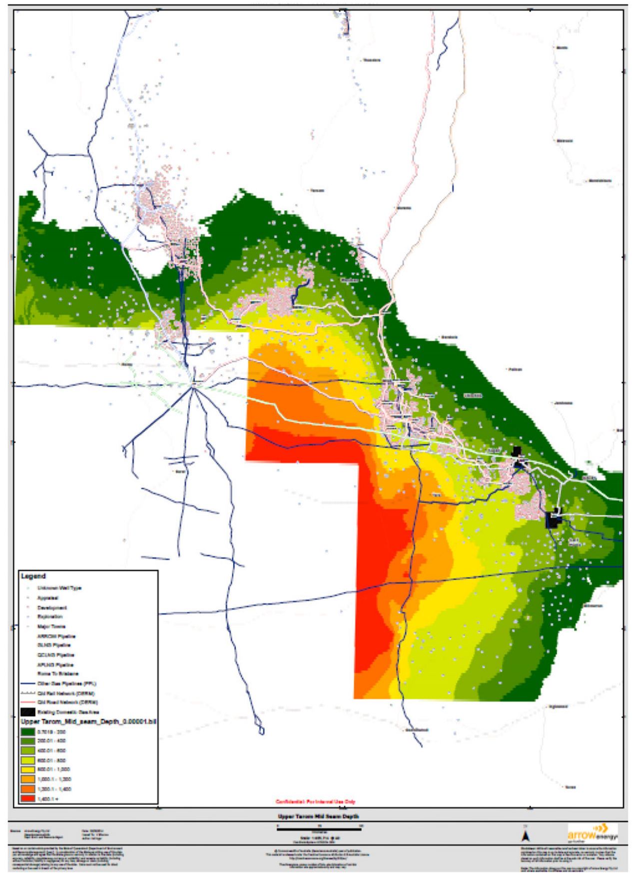

Figure 8—Depth contours for the Walloon Coal Measures (WCM) along the eastern Surat Basin

Chinchilla/Goondiwindi Slope Project Areas

All WCM proponents operate some section of this challenging, southern area of the Walloon fairway extending southward to the margins of the Surat Basin. Whilst the coals are deeper (see Figure 8), they are also thick and gas contents comparable to other areas of the Basin; however, the stress and permeability values are lower than the 'fairway' areas of the Surat Basin.

For example, the Ridgewood area was the site of a large hydraulic fracture diagnostic trial undertaken by QGC to hydraulic fracture these thick, challenging coals. The report of this experiment was documented in three papers and included: (i) results of DFITs for stress and permeability (see Figure 9); (ii) geomechanical studies; (ii) use of advanced pre- and post-frac sonic anisotropy logs and radioactive tracers for frac height determination; and (iii) hydraulic fracture history-matching of bottomhole treating pressure, surface deformation tiltmeter, and downhole microseismic monitoring data (see Figure 10) (Johnson et al. 2010a, Johnson et al. 2010b, Scott et al. 2010)(see Figure 10). The end determination of this and subsequent studies by QGC (Megorden, Jiang and Bentley 2013) was that sub-economic productivity largely resulted from the formation of a complex fracture, which poorly interconnected and instead directly stimulated a sparse and predominantly unidirectional natural fracture system in the WCM in this area of the Surat Basin. Similar results as well as overall poor responses due to low permeability

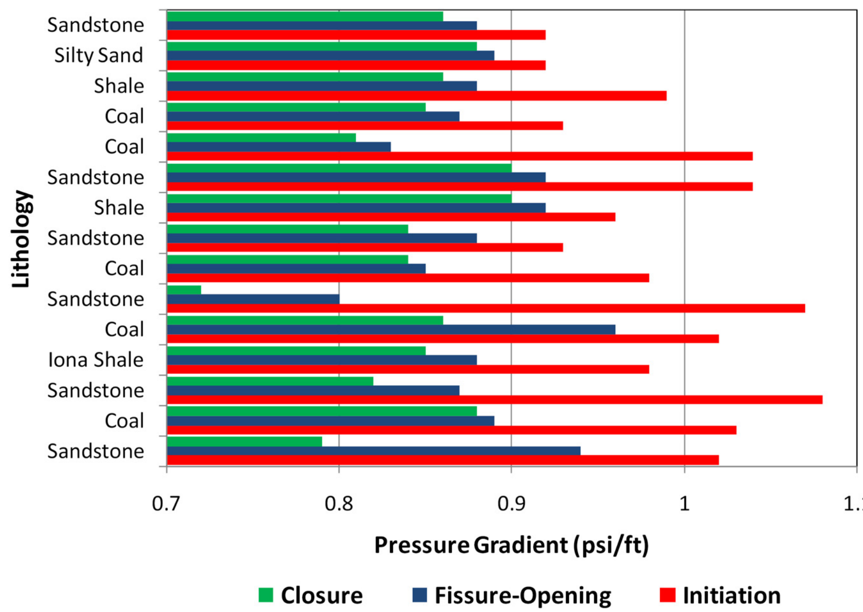

Figure 9—Closure, fissure-opening, and initiation pressures determined from DFIT at QGC Ridgewood study site (after Johnson et al., SPE 133066, 2010)

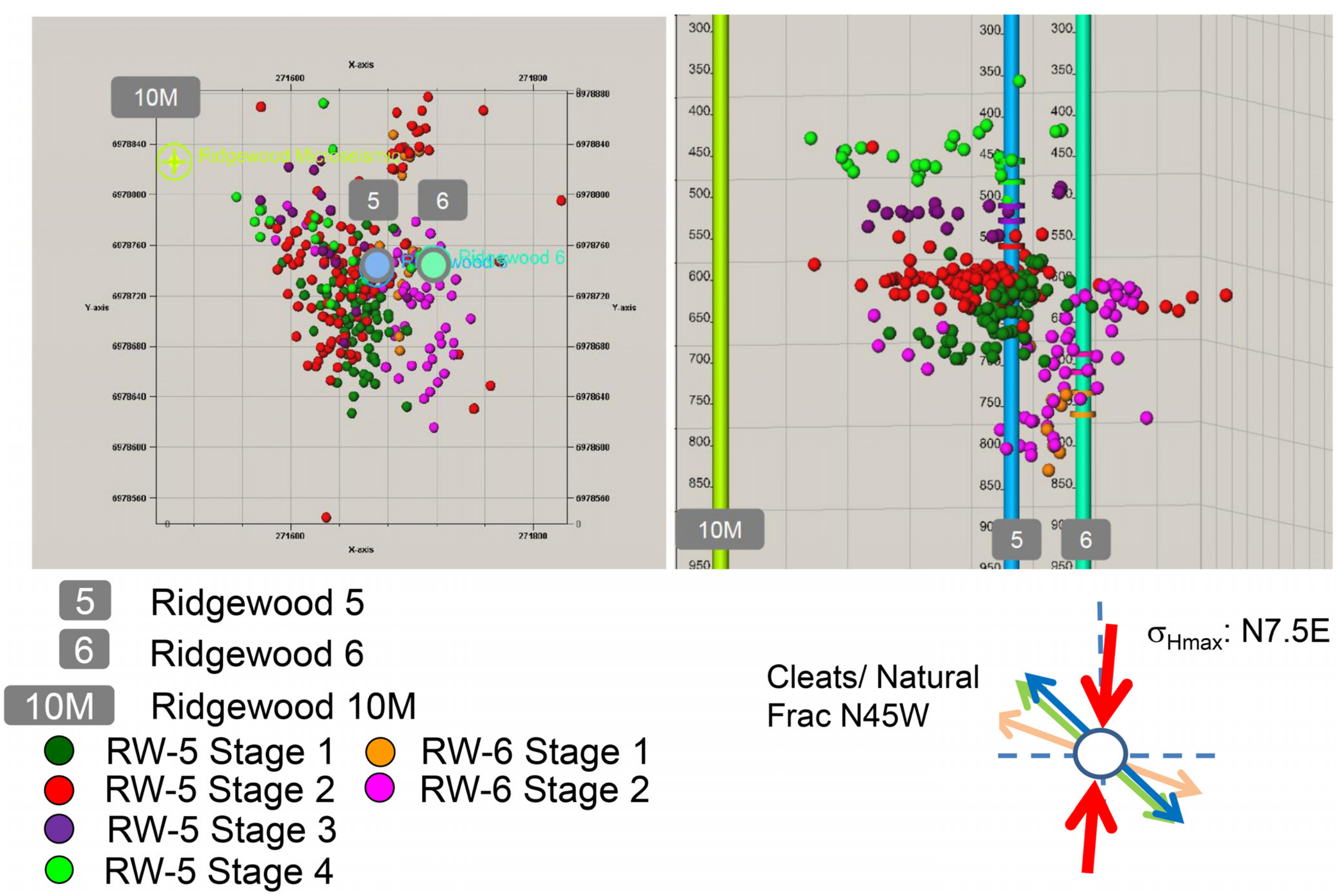

Figure 10—Stress orientations and microseismic responses at QGC Ridgewood study site that correlate well with surface deformation tiltmeter responses (after Johnson et al., SPE 133063, 2010)

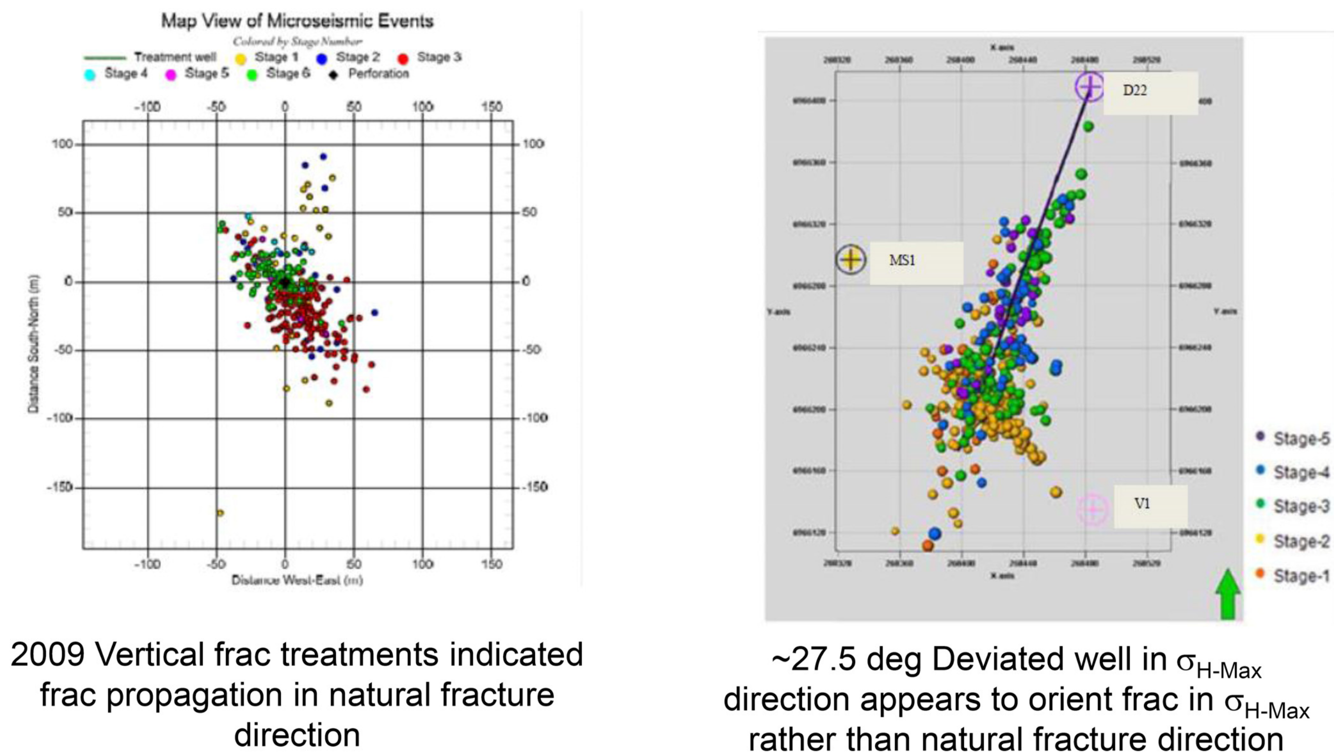

Figure 11—Stress orientations and microseismic responses at QGC Ridgewood study site that correlate well with surface deformation tiltmeter responses (after Megorden et al., SPE 167053, 2013)

were experienced by Origin Energy at a number of other sites across the Basin (Brooke-Barnett et al. 2013).

Recently, a positive experience was reported by QGC using a different strategy when revisiting a problematic area, which had similar fracturing behavior to the Ridgewood site (e.g., microseismic, tiltmeter, sonic anisotropy, and radioactive tracer data) but overall high productivity. In this case, QGC drilled two wells at 27.5 and 6 deg deviation in the $\sigma_{H\text{-}Max}$ direction and saw improved containment in the targeted intervals as well as improved fracture length in the $\sigma_{H\text{-}Max}$ direction resulting in noticeable but still uneconomic improvements in production relative to offset vertical, hydraulically fractured, producers (Megorden et al. 2013) (See Figure 11). This study documents the use of microseismic, tiltmeter, and pressure transient data that confirmed this effect within close proximity to the prior campaigns failed multi-stage treatment using a similar pumping schedule in a vertical wellbore. Origin reported that lower injection rates overall produced better results in these problematic regimes and categorically detailed microseismic responses encountered within the WCM as a function of depth (See Figure 12) (Brooke-Barnett et al. 2013).

Although these treatments demonstrate a large potential stimulated reservoir volume through these diagnostics, the effective propping of the narrow aperture, stress-sensitive, natural fractures may require addition of novel fluid and particle technologies such as that detailed by experimentation and modelling using selectively sized ultra-fine particles in specifically charged fluids to enhance the natural fracture conductivity (Keshavarz et al. 2014a, Keshavarz et al. 2014b). Therefore, experimentation is continuing in investigating potential strategies such as lower rates, successive treatments, injections of specifically charged fluids containing ultra-fine sized particles to stimulate small fractures and cleats, and optimisations of well deviations all warrant trials to try and unlock this area holding sizable resources in the WCM.

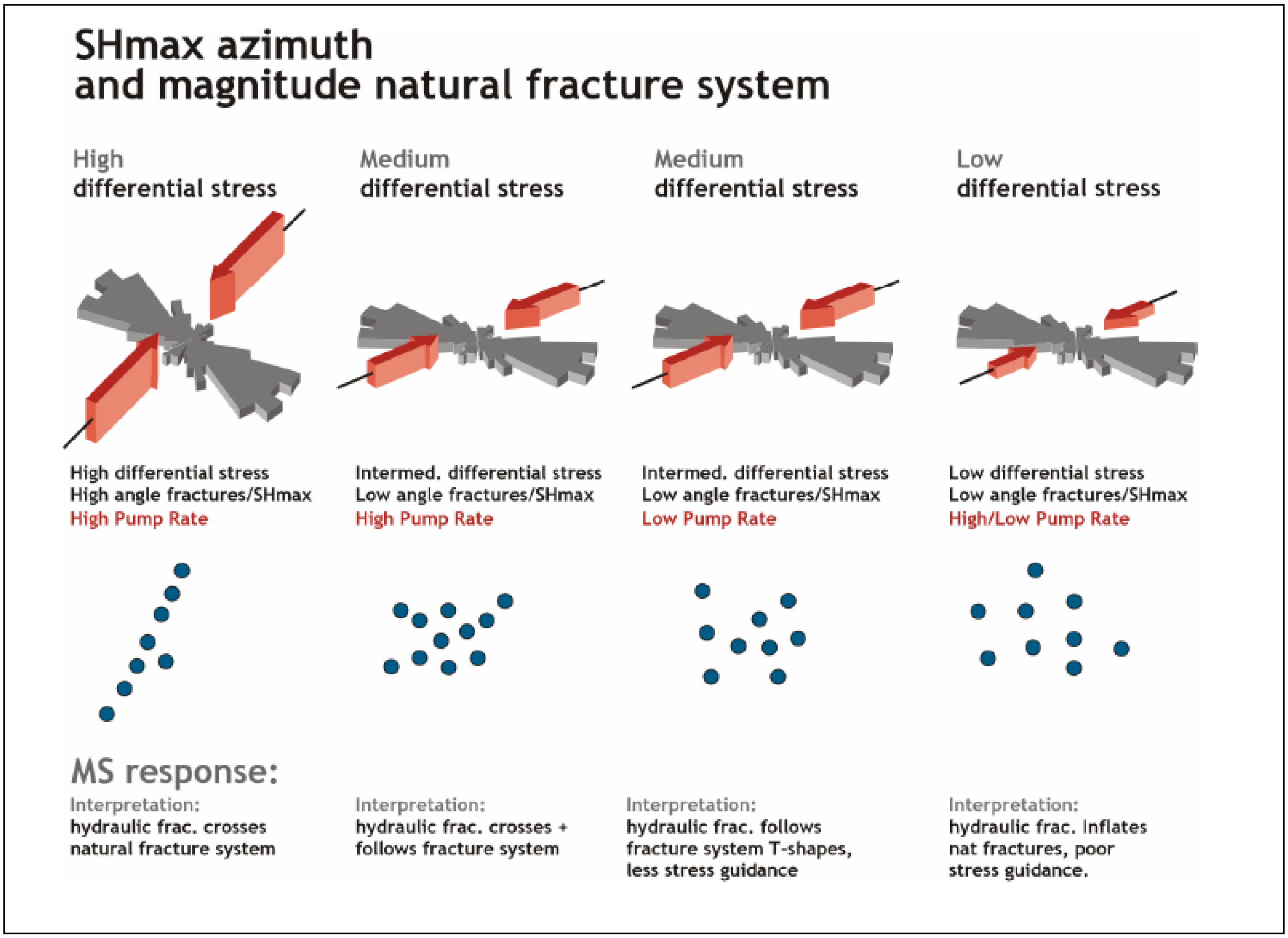

Figure 12—Correlation of microseismic patterns to stress regimes in the WCM (after Brooke-Barnett, et al., SPE 167064, 2013)

General Observations

From the authors' research and perspectives the following key factors emerge regarding successful CBM fields in Australia and based by area.

Northern Bowen Basin

The northern Bowen Basin remains a broad area of under-developed gas resources. Recent actions by the Queensland government to rationalize work programmes in a very busy environment has lessened the pressure on operators to move rapidly to improve solutions for this area, outside of the main producing areas. The general observations are:

- Shelfal locations in the West portions of the northern Bowen Basin have been developed in preference to the higher-stressed, lower-permeability eastern faulted/folded regions of the Basin.
- The implementation of surface-to-inseam (SIS) wells have improved both CBM and mine-drainage operations and will continue be optimised in the main operating areas.

Central Bowen Basin

- Anticlinal locations have been primary areas of development based on improved permeability and lower stress environments.
- The application of focused SIS wells on the best seams have made more consistent production results in Moura area than prior applications of multi-stage hydraulic fracturing treatments on the stacked coal sections in this area.

- Cavitation, laterals with fracture stimulations, and vertical wells with stimulations have been effective in Spring Gully/Fairview project areas. Some trials were made to improve production with laterals and multi-stage hydraulic fracturing, but the majority of production has been from vertical wells.
- Vertical wells with fracture stimulations dominated early development in Peat/Scotia fields and near conventional behavior on these highly permeable structures has reduced need for infill wells to achieve effective interference and drainage.

Surat Basin

- Open-hole completions dominate the production landscape as a result of early hydraulic fracturing failures.
- The Undulla Nose and Daandine areas have demonstrated higher production rates as a result of improved permeability, lower stress, laterally continuous coals and higher gas saturations.
- The Chinchilla/Goondiwindi slope remains a relatively sparsely developed area based on the inability to develop a successful strategy to stimulate these highly laminated, higher stress, and lower permeability coal seams of the Walloon Coal Measures.

Challenges and Recommendations

Further technologies and trials need to be targeted in thick, higher-stressed, lower-permeability coals of both the Bowen and Surat Basins that can include one or more of the following technologies.

- Further drilling technologies to maintain underbalanced to near balanced drilling conditions to reduce coal damage in areas of line, open-hole completions (e.g., SIS wells, lined openhole completions).
- A successful completion technique incorporating hydraulic fracturing of lateral wells (e.g., minable liners, isolation for selected longitudinal hydraulic fracturing, and multi-lateral reentry systems to allow clean outs and production management).
- Improved well azimuth planning for hydraulic fracturing using deviated wellbores the $\sigma_{H\text{-}Max}$ direction to take advantage of longitudinal or oblique oriented fractures and maximize standoff in thin coal intervals.
- Application of low rate, deep penetrating ultra-fine sized particles independently or in successive hydraulic fracturing treatments to take advantage of de-stressing and permeability enhancements of stress sensitive cleats to improve production from a large unpropped SRV being developed in low-permeability coal frac treatments.

In the WCM, fines production will continue in production operations during dewatering and may continue beyond dewatering based on initial hole instabilities. Operator support and production data t is important to progress detailed studies that will progress models on fines production based on actual field data. Such studies should not just theoretically progress our understanding but experiment with 'fit-for-purpose' solutions based on the modelled, physical mechanisms of fines production. Meanwhile, potential mechanical strategies (e.g., cement baskets, screens, and swell packers) should be piloted to gain further data in areas of high fines production and it is recommended to replace WCM with KCl brines during extended shut-in periods.

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